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(54) **LOW EMISSION TRIPLE-CYCLE POWER GENERATION AND CO_2 SEPARATION SYSTEMS AND METHODS**

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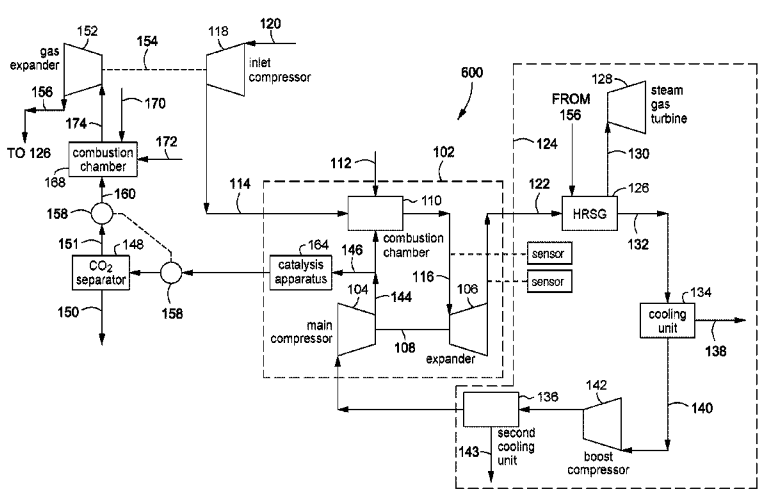
(57) **ABSTRACT**

Methods and systems for low emission power generation in combined cycle power plants are provided. One system includes a gas turbine system that stoichiometrically combusts a fuel and an oxidant in the presence of a compressed recycle stream to provide mechanical power and a gaseous exhaust. The compressed recycle stream acts as a diluent to moderate the temperature of the combustion process. A boost compressor can boost the pressure of the gaseous exhaust before being compressed into the compressed recycle stream. A purge stream is tapped off from the compressed recycle stream and directed to a $C0_2$ separator which discharges $C0_2$ and a nitrogen-rich gas which can be expanded in a gas expander to generate additional mechanical power.

15 Claims, 8 Drawing Sheets



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See application file for complete search history.

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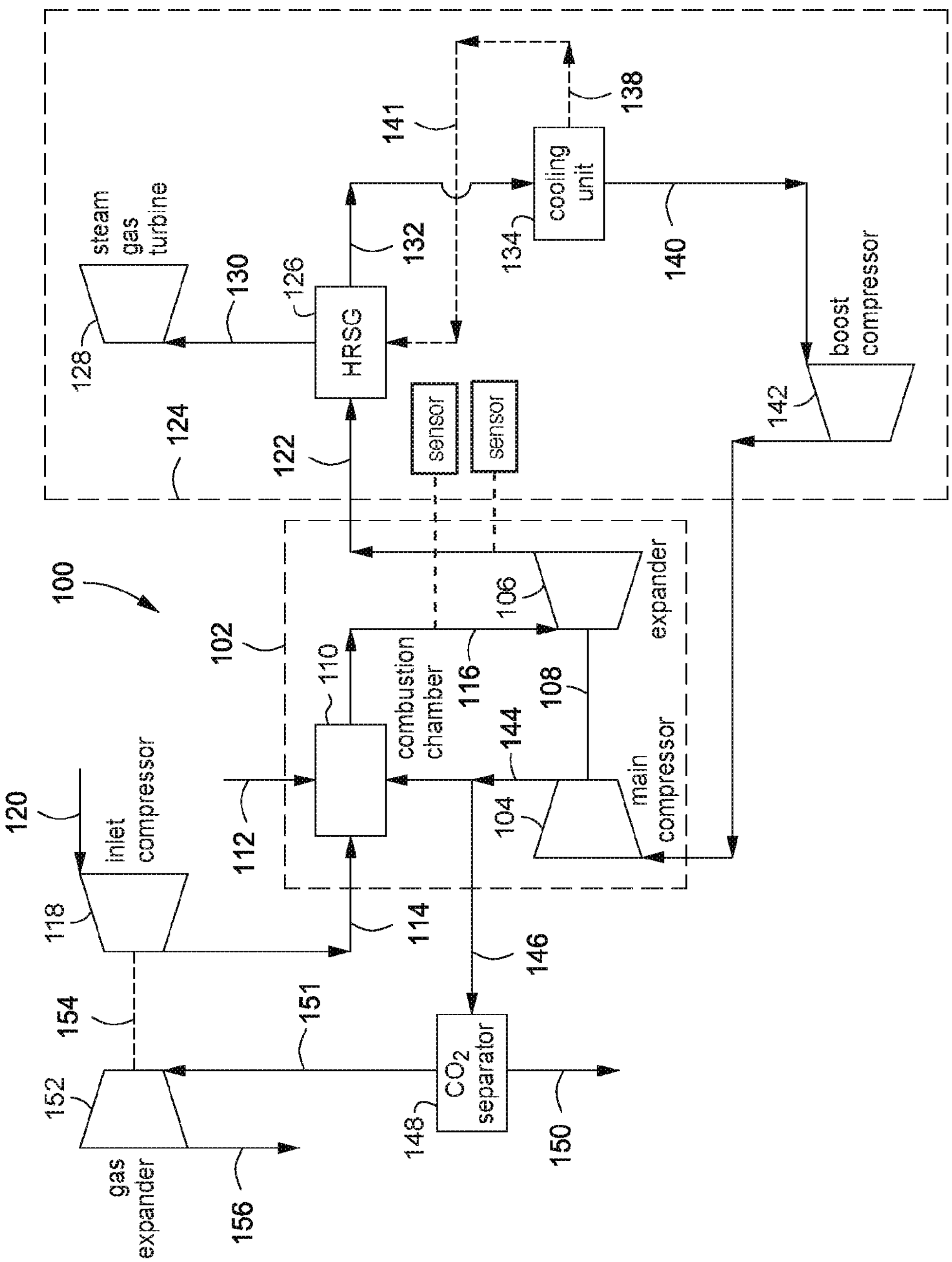
FIG. 1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104
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112
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122
124
126
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130
132
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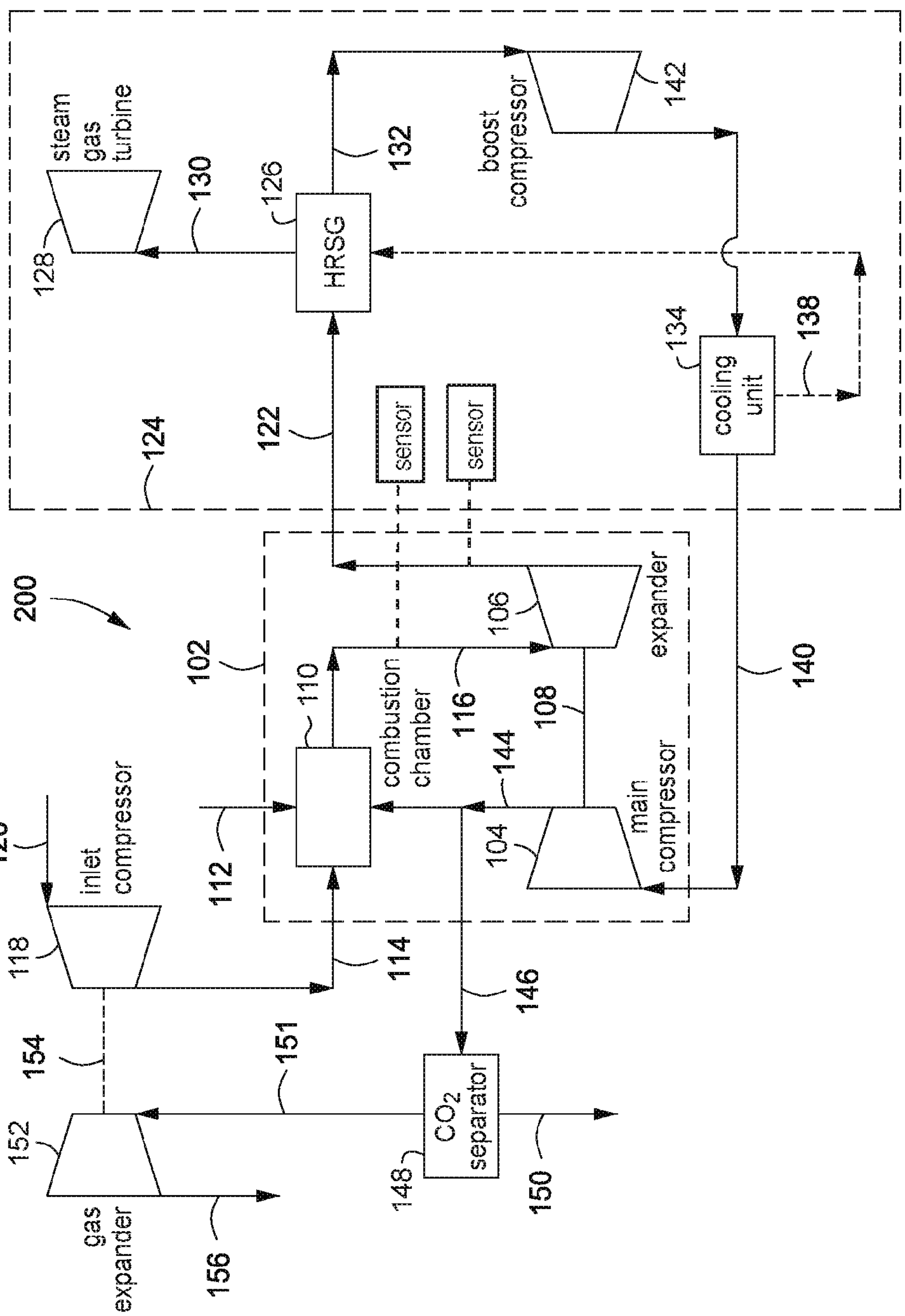
138
140
141
142
144
146
148
150
151
152
154
156
inlet compressor
combustion chamber
main compressor
expander
sensor
sensor
HRSG
steam gas turbine
cooling unit
boost compressor
CO_2 separator
gas expander

FIG. 2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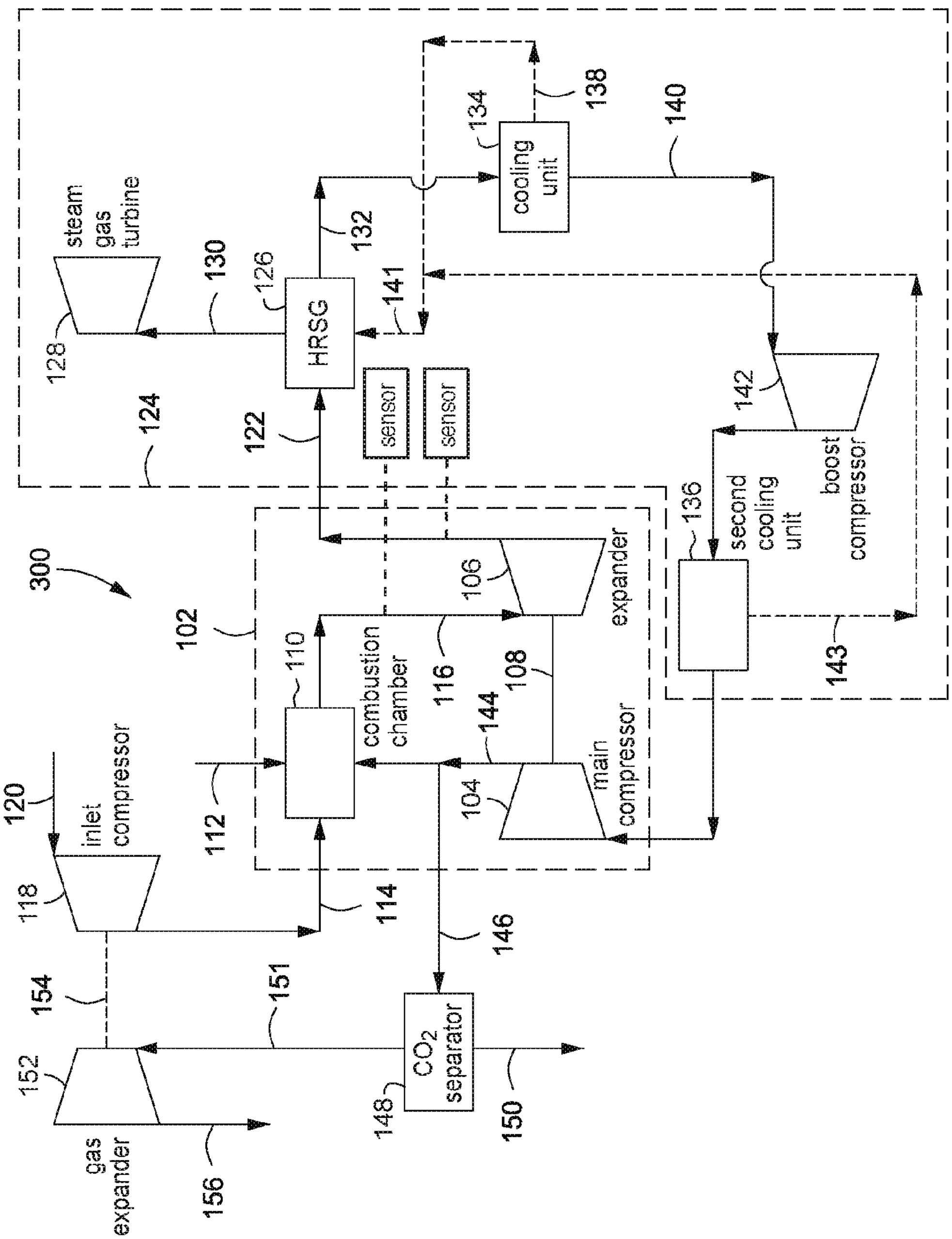
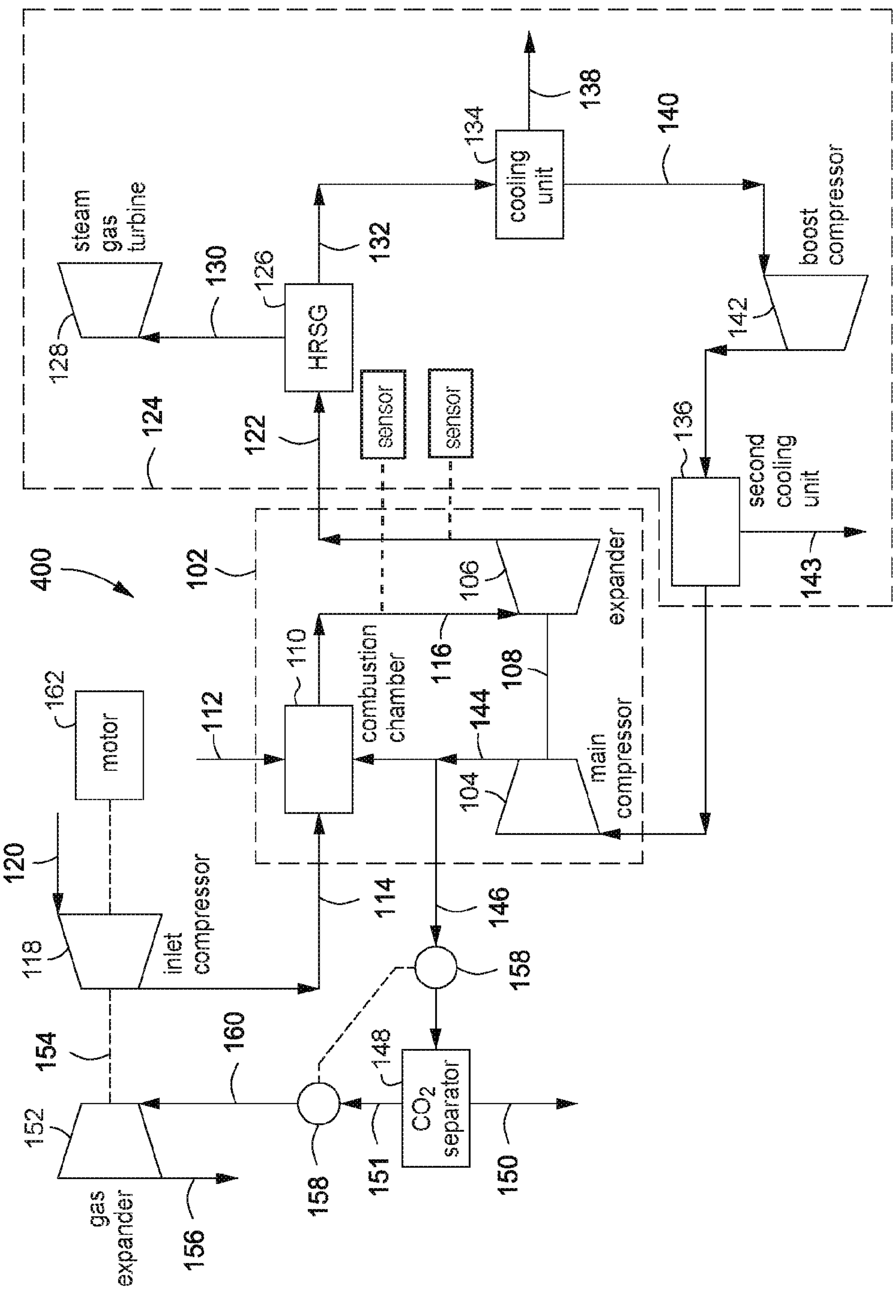
boost compressor
HRSG
sensor
sensor
cooling unit
expander
combustion chamber
inlet compressor
main compressor
CO_2 separator
gas expander
200
102
104
106
108
110
112
114
116
118
120
122
124
126
128
130
132
134
138
140
142
144
146
148
150
151
152
154
156

FIG. 3


300
102
124
steam gas turbine
128
130
126
HRSG
132
141
cooling unit
134
138
140
sensor
sensor
122
boost compressor
142
second cooling unit
136
143
expander
106
116
110
combustion chamber
108
144
main compressor
104
112
inlet compressor
118
120
114
146
CO2 separator
148
150
151
154
152
gas expander
156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102
124
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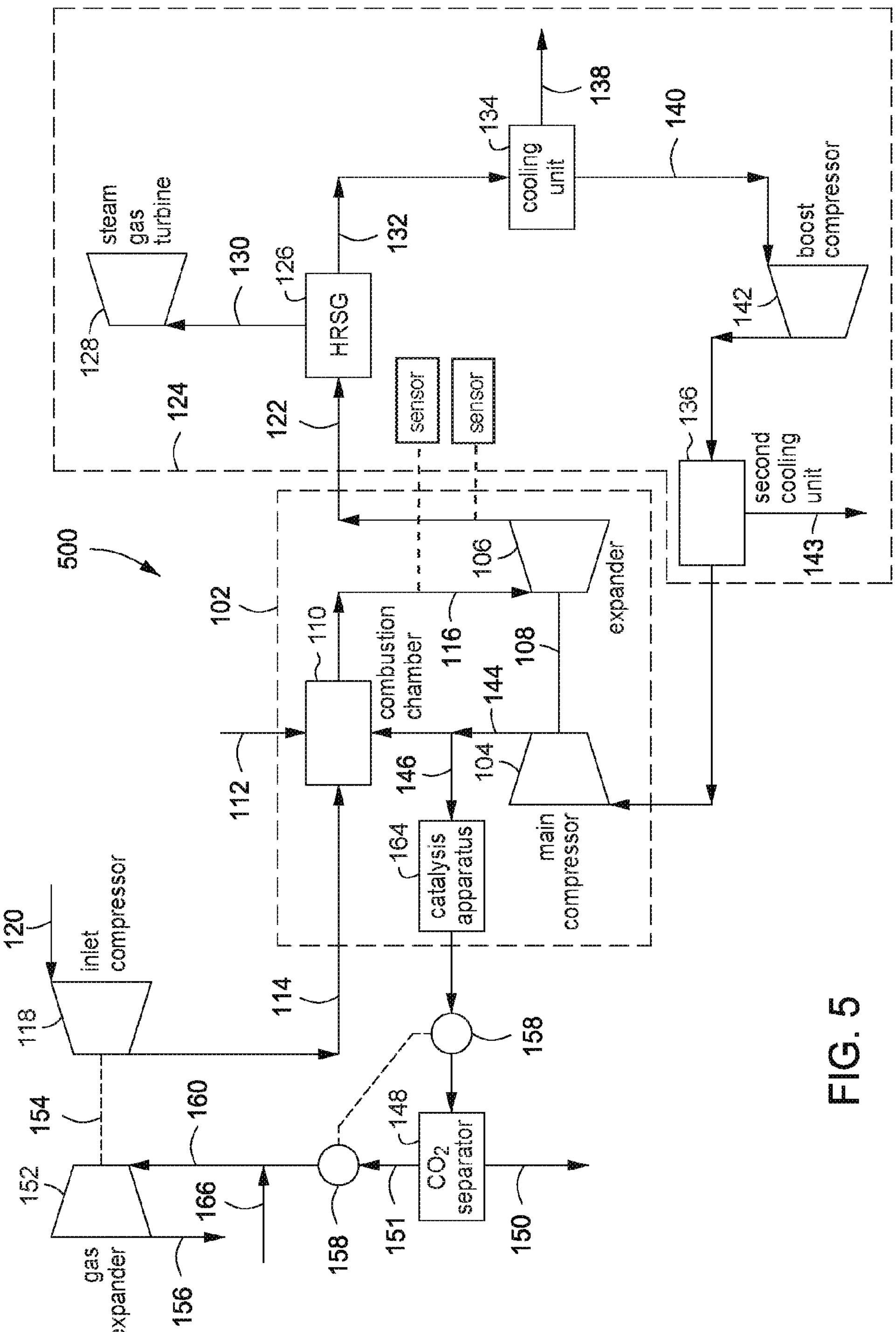
128
130
126
HRSG
132
122
134
cooling unit
138
140
boost compressor
142
sensor
sensor
136
second cooling unit
143
106
expander
110
combustion chamber
116
108
112
144
104
main compressor
motor
162
120
inlet compressor
118
114
146
158
154
160
148
CO_2 separator
152
gas expander
156
158
151
150

FIG. 4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102
124
steam gas turbine
128
130
126
HRSG
122
132
cooling unit
134
138
140
boost compressor
142
136
second cooling unit
143
sensor
sensor
106
expander
116
108
110
combustion chamber
112
144
146
104
main compressor
164
catalysis apparatus
120
inlet compressor
118
114
158
154
160
152
148
CO_2 separator
166
151
150
158
gas expander
156

FIG. 5

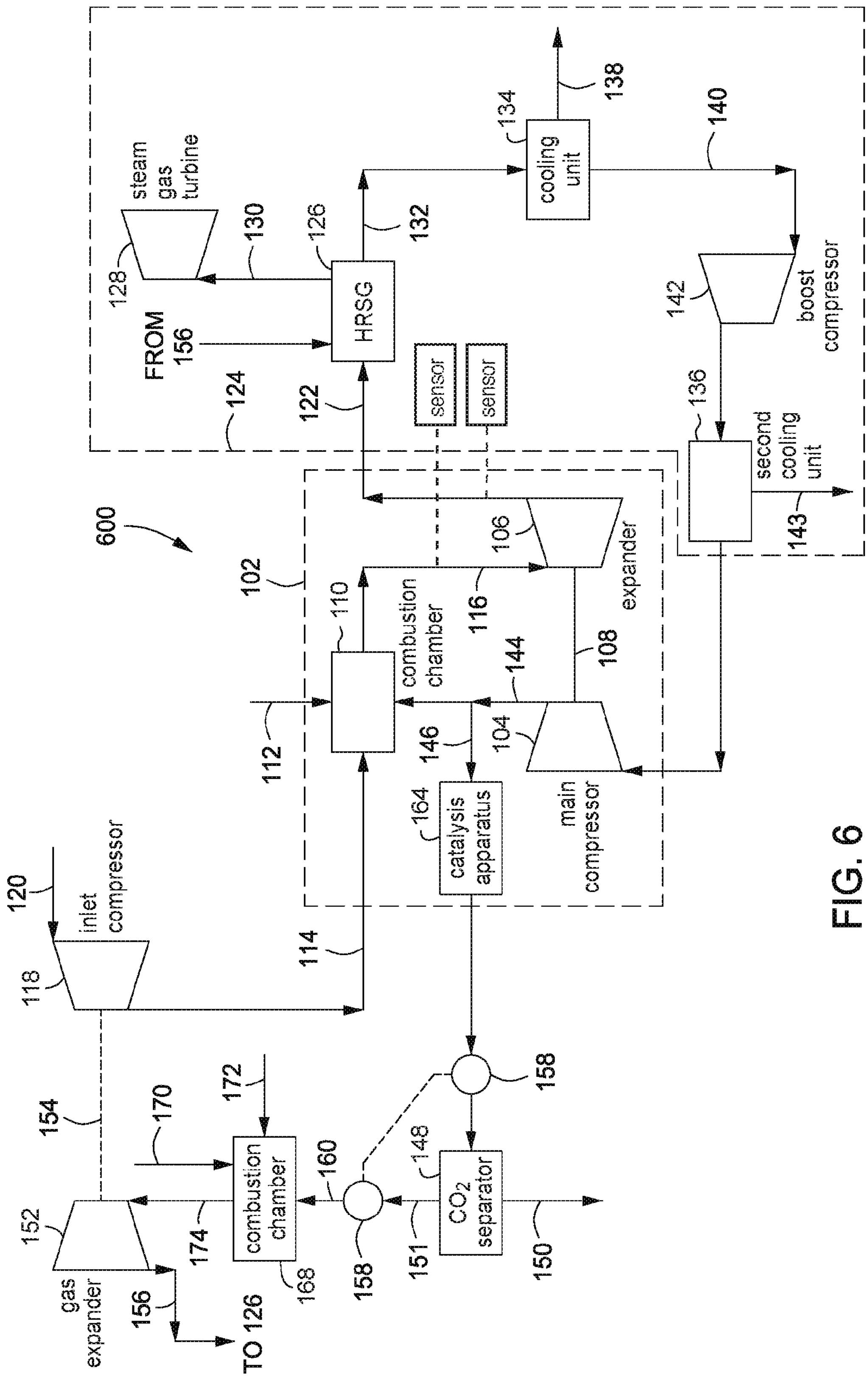
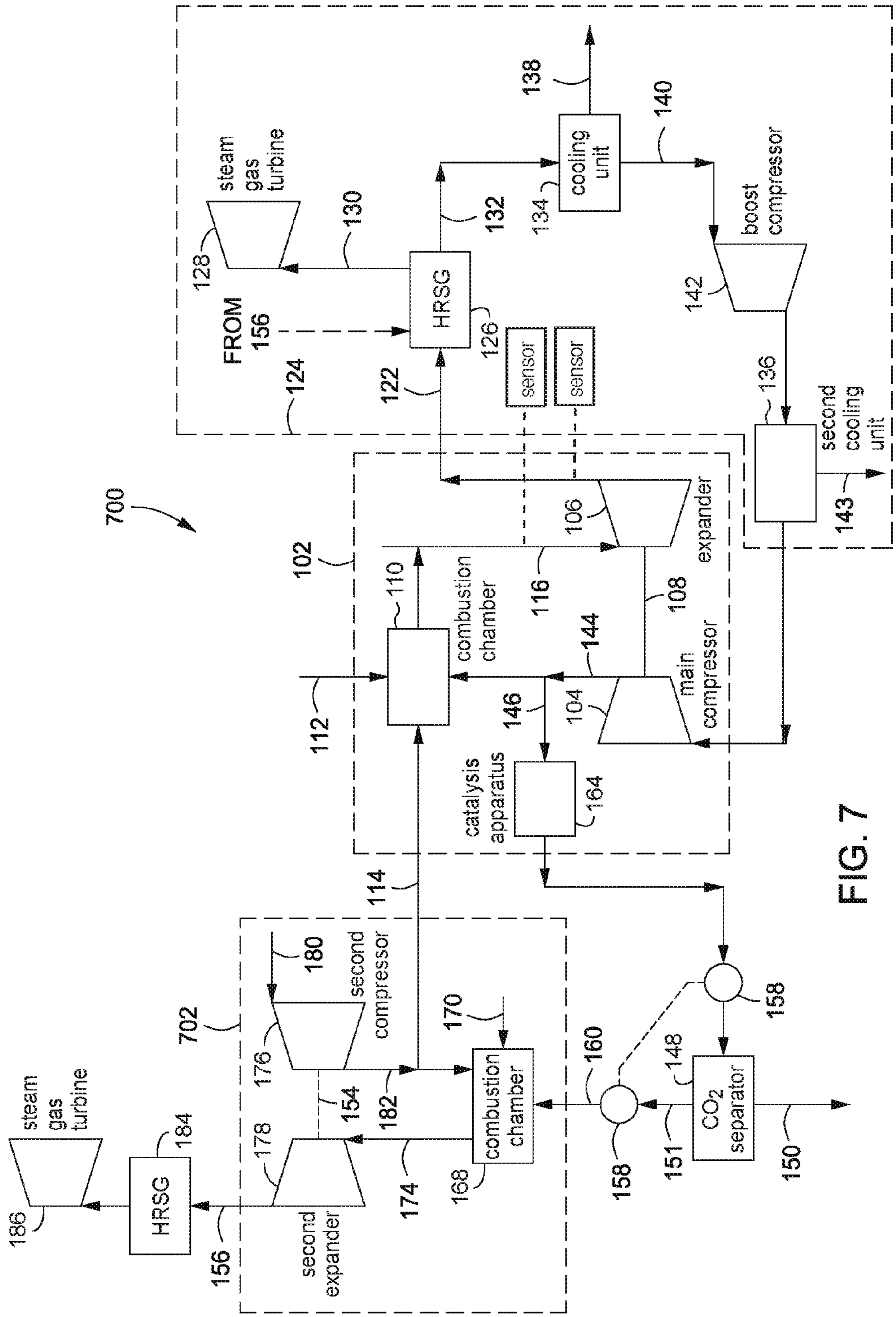

600
102
124
steam gas turbine
128
130
126
HRSG
FROM 156
132
134
cooling unit
138
140
142
boost compressor
136
second cooling unit
143
122
sensor
sensor
106
expander
108
116
110
combustion chamber
144
112
146
104
main compressor
164
catalysis apparatus
114
120
inlet compressor
118
158
154
170
172
combustion chamber
168
160
148
CO_2 separator
151
150
152
gas expander
174
156
TO 126

FIG. 6


700
steam gas turbine
cooling unit
boost compressor
HRSG
FROM 156
sensor
sensor
second cooling unit
expander
combustion chamber
main compressor
catalysis apparatus
second compressor
combustion chamber
second expander
HRSG
steam gas turbine
CO_2 separator
102
104
106
108
110
112
114
116
122
124
126
128
130
132
134
136
138
140
142
143
144
146
148
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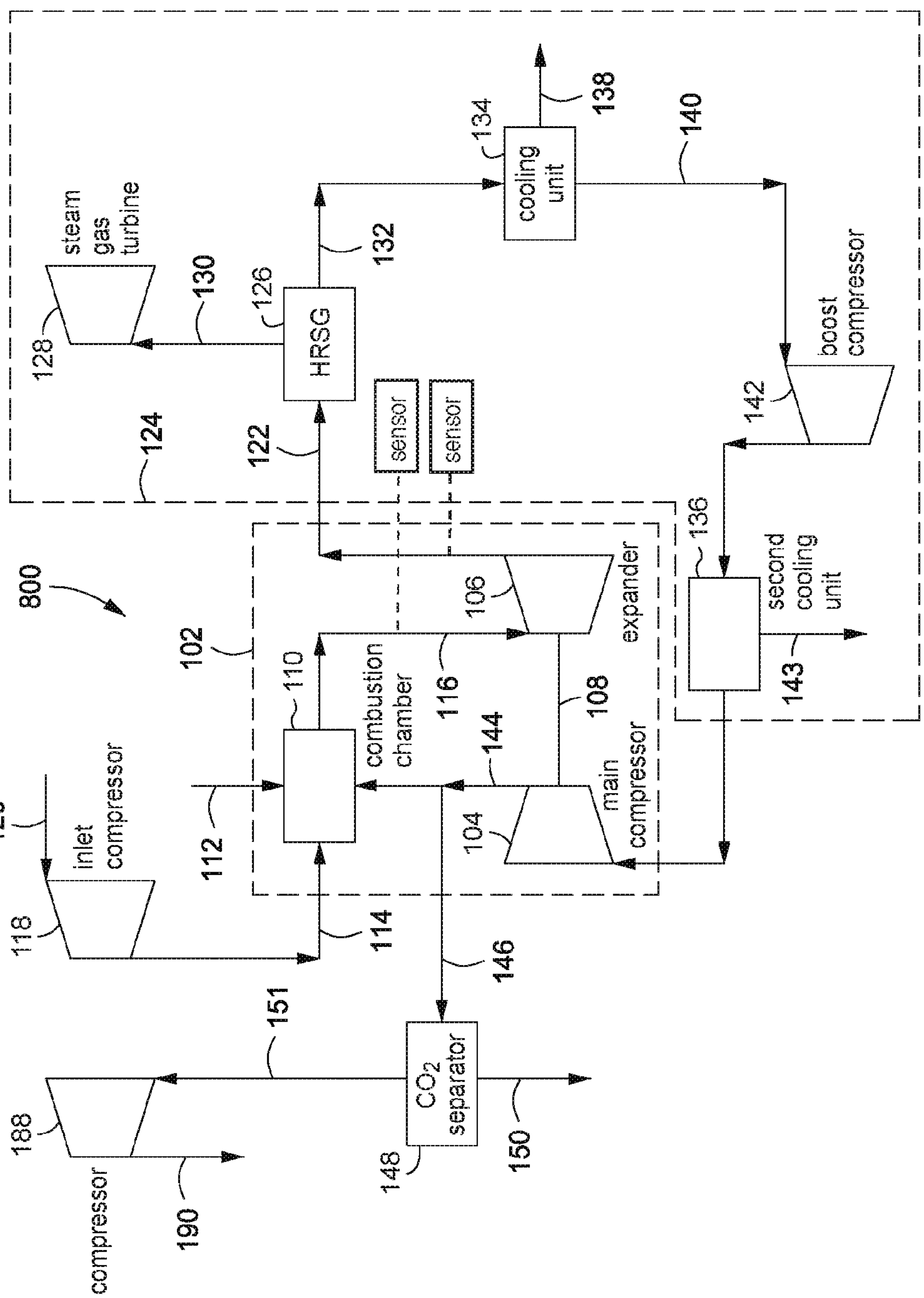
702

FIG. 7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102
124
steam gas turbine
128
130
126
HRSG
122
132
cooling unit
134
138
140
boost compressor
142
sensor
sensor
136
second cooling unit
143
expander
106
116
combustion chamber
110
108
144
main compressor
104
112
inlet compressor
120
118
114
146
151
CO_2 separator
148
150
188
compressor
190

FIG. 8

LOW EMISSION TRIPLE-CYCLE POWER GENERATION AND CO_2 SEPARATION SYSTEMS AND METHODS

CROSS-REFERENCE TO RELATED APPLICATIONS

This application is the National Stage entry under 35 U.S.C. 371 of PCT/US2011/039826, that published as WO 2012/003077 and was filed on 9 Jun. 2011 which claims the benefit of U.S. Provisional Application No. 61/361,173, filed on 2 Jul. 2010, each of which is incorporated by reference, in its entirety, for all purposes.

This application contains subject matter related to PCT/US2011/042870, that published as WO 2012/003489 and was filed on 1 Jul. 2011; PCT/US2011/039824, that published as WO 2012/003076 and was filed on 9 Jun. 2011; PCT/US2011/039828, that published as WO 2012/003078 and was filed on 9 Jun. 2011; PCT/US2011/039829, that published as WO 2012/003079 and was filed on 9 Jun. 2011; and PCT/US2011/039830, that published as WO 2012/003080 and was filed on 9 Jun. 2011.

FIELD OF THE DISCLOSURE

Embodiments of the disclosure relate to low emission power generation in combined-cycle power systems. More particularly, embodiments of the disclosure relate to methods and apparatuses for stoichiometrically combusting a fuel for enhanced CO_2 manufacture and capture, and expansion or compression of nitrogen-rich gas.

BACKGROUND OF THE DISCLOSURE

This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Many oil producing countries are experiencing strong domestic growth in power demand and have an interest in enhanced oil recovery (EOR) to improve oil recovery from their reservoirs. Two common EOR techniques include nitrogen (N_2) injection for reservoir pressure maintenance and carbon dioxide (CO_2) injection for miscible flooding for EOR. There is also a global concern regarding green house gas (GHG) emissions. This concern combined with the implementation of cap-and-trade policies in many countries make reducing CO_2 emissions a priority for these and other countries as well as the companies that operate hydrocarbon production systems therein.

Some approaches to lower CO_2 emissions include fuel de-carbonization or post-combustion capture using solvents, such as amines. However, both of these solutions are expensive and reduce power generation efficiency, resulting in lower power production, increased fuel demand and increased cost of electricity to meet domestic power demand. In particular, the presence of oxygen, SO_X, and NO_X components makes the use of amine solvent absorption very problematic. Another approach is an oxyfuel gas turbine in a combined cycle (e.g., where exhaust heat from the gas turbine Brayton cycle is captured to make steam and produce additional power in a Rankin cycle). However, there are no commercially available gas turbines that can operate in such a cycle and the power required to produce high purity oxygen significantly reduces the overall efficiency of the process. Several studies have compared these processes and show some of the advantages of each approach. See, e.g. Bolland, Olav, and Undrum, Henriette, *Removal of CO_2 from Gas Turbine Power Plants: Evaluation of pre- and post-combustion methods*, SINTEF Group, found at http://www.energy.sintef.no/publ/xergi/98/3/3 art-8-engelsk.htm (1998).

Other approaches to lower CO_2 emissions include stoichiometric exhaust gas recirculation, such as in natural gas combined cycles (NGCC). In a conventional NGCC system, only about 40% of the air intake volume is required to provide adequate stoichiometric combustion of the fuel, while the remaining 60% of the air volume serves to moderate the temperature and cool the flue gas so as to be suitable for introduction into the succeeding expander, but also disadvantageously generate an excess oxygen byproduct which is difficult to remove. The typical NGCC produces low pressure flue gas which requires a fraction of the power produced to extract the CO_2 for sequestration or EOR, thereby reducing the thermal efficiency of the NGCC. Further, the equipment for the CO_2 extraction is large and expensive, and several stages of compression are required to take the ambient pressure gas to the pressure required for EOR or sequestration. Such limitations are typical of post-combustion carbon capture from low pressure flue gas associated with the combustion of other fossil fuels, such as coal.

Accordingly, there is still a substantial need for a low emission, high efficiency power generation and CO_2 capture or manufacture process.

SUMMARY OF THE DISCLOSURE

The present disclosure is directed to triple-cycle power generation systems and methods of operating the system. In one exemplary system, an integrated system comprises a gas turbine system, an exhaust gas recirculation system, and a gas expander. The gas turbine system has a first combustion chamber configured to stoichiometrically combust a first compressed oxidant and a first fuel in the presence of a compressed recycle stream. The combustion chamber directs a first discharge stream to an expander to generate a gaseous exhaust stream and at least partially drive a main compressor. The exhaust gas recirculation system receives the gaseous exhaust stream from the expander of the gas turbine system and produces power from the heat energy contained therein, such as through a heat recovery steam generation unit. The exhaust gas recirculation system further routes the exhaust gas stream to the main compressor where it is compressed to generate the compressed recycle stream. The compressed recycle stream is directed to the combustion chamber to act as a diluent configured to moderate the temperature of the first discharge stream. The integrated system further includes a CO_2 separator fluidly coupled to the compressed recycle stream via a purge stream. The CO_2 separator generates a CO_2-rich stream and a residual stream, comprising nitrogen-rich gas, from the purge stream. As indicated above, the integrated system also includes a gas expander. The gas expander is fluidly coupled to the CO_2 separator via the residual stream as is adapted to generate power by expanding the residual stream.

In an exemplary method of operating a triple-cycle power generation system, a method of generating power may comprise stoichiometrically combusting a first compressed oxidant and a first fuel in a first combustion chamber and in the presence of a compressed recycle stream. The combustion may thereby generate a first discharge stream. The compressed recycle stream may act as a diluent configured to moderate the temperature of the first discharge stream. The method further includes expanding the first discharge stream in an expander to at least partially drive a first compressor and generate a gaseous exhaust stream. The expansion of the first discharge stream may generate additional power for other uses. The method further includes directing the gaseous exhaust stream into the first compressor, wherein the first compressor compresses the gaseous exhaust stream and thereby generates the compressed recycle stream. Still further, the method includes extracting a portion of the compressed recycle stream to a CO_2 separator via a purge stream, the CO_2 separator being fluidly coupled to a gas expander via a residual stream derived from the CO_2 separator and consisting primarily of nitrogen-rich gas. The exemplary method further includes expanding the residual stream in a gas expander to generate mechanical power and an exhaust gas.

BRIEF DESCRIPTION OF THE DRAWINGS

The foregoing and other advantages of the present disclosure may become apparent upon reviewing the following detailed description and drawings of non-limiting examples of embodiments in which:

FIG. **1** depicts an integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **2** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **3** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **4** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **5** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **6** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **7** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

FIG. **8** depicts another integrated system for low emission power generation and enhanced CO_2 recovery, according to one or more embodiments of the present disclosure.

DETAILED DESCRIPTION OF THE DISCLOSURE

In the following detailed description section, the specific embodiments of the present disclosure are described in connection with preferred embodiments. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present disclosure, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the disclosure is not limited to the specific embodiments described below, but rather, it includes all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

Various terms as used herein are defined below. To the extent a term used in a claim is not defined below, it should

be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent.

As used herein, the term "natural gas" refers to a multi-component gas obtained from a crude oil well (associated gas) or from a subterranean gas-bearing formation (non-associated gas). The composition and pressure of natural gas can vary significantly. A typical natural gas stream contains methane (CH_4) as a major component, i.e. greater than 50 mol % of the natural gas stream is methane. The natural gas stream can also contain ethane (C_2H_6), higher molecular weight hydrocarbons (e.g., C_3-C_{20} hydrocarbons), one or more acid gases (e.g., hydrogen sulfide, carbon dioxide), or any combination thereof. The natural gas can also contain minor amounts of contaminants such as water, nitrogen, iron sulfide, wax, crude oil, or any combination thereof.

As used herein, the term "stoichiometric combustion" refers to a combustion reaction having a volume of reactants comprising a fuel and an oxidizer and a volume of products formed by combusting the reactants where the entire volume of the reactants is used to form the products. As used herein, the term "substantially stoichiometric combustion" refers to a combustion reaction having a molar ratio of combustion fuel to oxygen ranging from about plus or minus 10% of the oxygen required for a stoichiometric ratio or more preferably from about plus or minus 5% of the oxygen required for the stoichiometric ratio. For example, the stoichiometric ratio of fuel to oxygen for methane is 1:2 ($CH_4+2O_2>CO_2+2H_2O$). Propane will have a stoichiometric ratio of fuel to oxygen of 1:5. Another way of measuring substantially stoichiometric combustion is as a ratio of oxygen supplied to oxygen required for stoichiometric combustion, such as from about 0.9:1 to about 1.1:1, or more preferably from about 0.95:1 to about 1.05:1

As used herein, the term "stream" refers to a volume of fluids, although use of the term stream typically means a moving volume of fluids (e.g., having a velocity or mass flow rate). The term "stream," however, does not require a velocity, mass flow rate, or a particular type of conduit for enclosing the stream.

Embodiments of the presently disclosed systems and processes may be used to produce ultra low emission electric power and CO_2 for enhanced oil recovery (EOR) or sequestration applications. According to embodiments disclosed herein, a mixture of air and fuel can be stoichiometrically combusted and simultaneously mixed with a stream of recycled exhaust gas. The stream of recycled exhaust gas, generally including products of combustion such as CO_2, can be used as a diluent to control or otherwise moderate the temperature of the stoichiometric combustion and flue gas entering the succeeding expander.

Combustion at near stoichiometric conditions (or "slightly rich" combustion) can prove advantageous in order to eliminate the cost of excess oxygen removal. By cooling the flue gas and condensing the water out of the stream, a relatively high content CO_2 stream can be produced. While a portion of the recycled exhaust gas can be utilized for temperature moderation in the closed Brayton cycle, a remaining purge stream can be used for EOR applications and electric power can be produced with little or no SO_X, NO_X, or CO_2 being emitted to the atmosphere. For example, according to embodiments disclosed herein, the purge stream can be treated in a CO_2 separator adapted to discharge a nitrogen-rich gas which can be subsequently expanded in a gas expander to generate additional mechanical power. The result of the systems disclosed herein is the production of power in three separate cycles and the manufacturing or capture of additional CO_2 at a more economically efficient level. In some implementations, the nitrogen-rich discharge stream may be heated through various means to increase the power obtainable through the expander on the nitrogen stream. Additionally, in some implementations, the nitrogen vent following the expander can be cooled and used to provide refrigeration, which can be used to improve the efficiency of the compressor(s) in the Brayton cycle and/or in recycling the exhaust gas. The cold nitrogen stream could also be used in other applications that improve the process efficiency.

Alternatively, the discharged nitrogen-rich gas can be sent to EOR facilities for additional compression and/or injection into wells for oil recovery and/or pressure maintenance. Although it is possible to produce nitrogen for reservoir pressure maintenance and CO_2 for EOR completely independently, embodiments disclosed herein take advantage of the synergies that are possible when both nitrogen and CO_2 are produced in an integrated process to accomplish the production of these gases at a much lower cost while also producing power.

Referring now to the figures, FIG. **1** illustrates a power generation system **100** configured to provide an improved post-combustion CO_2 capture process using a combined-cycle arrangement. In at least one embodiment, the power generation system **100** can include a gas turbine system **102** that can be characterized as a closed Brayton cycle. In one embodiment, the gas turbine system **102** can have a first or main compressor **104** coupled to an expander **106** through a common shaft **108** or other mechanical, electrical, or other power coupling, thereby allowing a portion of the mechanical energy generated by the expander **106** to drive the compressor **104**. The expander **106** may generate power for other uses as well. The gas turbine system **102** can be a standard gas turbine, where the main compressor **104** and expander **106** form the compressor and expander ends, respectively, of the standard gas turbine. In other embodiments, however, the main compressor **104** and expander **106** can be individualized components in a system **102**.

The gas turbine system **102** can also include a combustion chamber **110** configured to combust a fuel stream **112** mixed with a compressed oxidant **114**. In one or more embodiments, the fuel stream **112** can include any suitable hydrocarbon gas or liquid, such as natural gas, methane, ethane, naphtha, butane, propane, syngas, diesel, kerosene, aviation fuel, coal derived fuel, bio-fuel, oxygenated hydrocarbon feedstock, or combinations thereof. The compressed oxidant **114** can be derived from a second or inlet compressor **118** fluidly coupled to the combustion chamber **110** and adapted to compress a feed oxidant **120**. In one or more embodiments, the feed oxidant **120** can include any suitable gas containing oxygen, such as air, oxygen-rich air, oxygen-depleted air, pure oxygen, or combinations thereof.

As will be described in more detail below, the combustion chamber **110** can also receive a compressed recycle stream **144**, including a flue gas primarily having CO_2 and nitrogen components. The compressed recycle stream **144** can be derived from the main compressor **104** and adapted to help facilitate the stoichiometric combustion of the compressed oxidant **114** and fuel **112**, and also increase the CO_2 concentration in the working fluid. A discharge stream **116** directed to the inlet of the expander **106** can be generated as a product of combustion of the fuel stream **112** and the compressed oxidant **114**, in the presence of the compressed recycle stream **144**. In at least one embodiment, the fuel stream **112** can be primarily natural gas, thereby generating a discharge **116** including volumetric portions of vaporized water, CO_2, nitrogen, nitrogen oxides (NOx), and sulfur oxides (SO_X). In some embodiments, a small portion of unburned fuel **112** or other compounds may also be present in the discharge **116** due to combustion equilibrium limitations. As the discharge stream **116** expands through the expander **106** it generates mechanical power to drive the main compressor **104**, an electrical generator, or other facilities, and also produces a gaseous exhaust stream **122** having a heightened CO_2 content.

The power generation system **100** can also include an exhaust gas recirculation (EGR) system **124**. While the EGR system **124** illustrated in the figures incorporates various apparati, the illustrated configurations are representative only and any system that recirculates the exhaust gas **122** back to the main compressor may be used. In one or more embodiments, the EGR system **124** can include a heat recovery steam generator (HRSG) **126**, or similar device, fluidly coupled to a steam gas turbine **128**. In at least one embodiment, the combination of the HRSG **126** and the steam gas turbine **128** can be characterized as a closed Rankine cycle. In combination with the gas turbine system **102**, the HRSG **126** and the steam gas turbine **128** can form part of a combined-cycle power generating plant, such as a natural gas combined-cycle (NGCC) plant. The gaseous exhaust stream **122** can be sent to the HRSG **126** in order to generate a stream of steam **130** and a cooled exhaust gas **132**. In some embodiments, the steam **130** can be sent to the steam gas turbine **128** to generate additional electrical power.

FIG. **1** illustrates additional apparatus in the EGR system **124** that optionally may be incorporated in some implementations. The cooled exhaust gas **132** can be sent to at least one cooling unit **134** configured to reduce the temperature of the cooled exhaust gas **132** and generate a cooled recycle gas stream **140**. In one or more embodiments, the cooling unit **134** can be a direct contact cooler, trim cooler, a mechanical refrigeration unit, or combinations thereof. The cooling unit **134** can also be configured to remove a portion of condensed water via a water dropout stream **138** which can, in at least one embodiment, be routed to the HRSG **126** via line **141** to provide a water source for the generation of additional steam **130**. In one or more embodiments, the cooled recycle gas stream **140** can be directed to a boost compressor **142** (if required) fluidly coupled to the cooling unit **134**. Cooling the cooled exhaust gas **132** in the cooling unit **134** can reduce the power required to compress the cooled recycle gas stream **140** in the boost compressor **142** or eliminate the need for it altogether.

The boost compressor **142** can be configured to increase the pressure of the cooled recycle gas stream **140** before it is introduced into the main compressor **104**. As opposed to a conventional fan or blower system, the boost compressor **142** increases the overall density of the cooled recycle gas stream **140**, thereby directing an increased mass flow rate for the same volumetric flow to the main compressor **104**. Because the main compressor **104** is typically volume-flow limited, directing more mass flow through the main compressor **104** can result in a higher discharge pressure from the main compressor **104**, thereby translating into a higher pressure ratio across the expander **106**. A higher pressure ratio generated across the expander **106** can allow for higher inlet temperatures and, therefore, an increase in expander **106** power and efficiency. This can prove advantageous since the CO_2-rich discharge **116** generally maintains a higher specific heat capacity. Accordingly, the cooling unit

134 and the boost compressor 142, when incorporated, may each be adapted to optimize or improve the operation of the gas turbine system 102.

The main compressor 104 can be configured to compress the cooled recycle gas stream 140 received from the EGR system 124, such as from the boost compressor 142, to a pressure nominally above the combustion chamber 110 pressure, thereby generating the compressed recycle stream 144. In at least one embodiment, a purge stream 146 can be tapped from the compressed recycle stream 144 and subsequently treated in a CO_2 separator 148 to capture CO_2 at an elevated pressure via line 150. The separated CO_2 in line 150 can be used for sales, used in another process requiring carbon dioxide, and/or compressed and injected into a terrestrial reservoir for enhanced oil recovery (EOR), sequestration, or another purpose.

A residual stream 151, essentially depleted of CO_2 and consisting primarily of nitrogen, can be derived from the CO_2 separator 148. In one or more embodiments, the residual stream 151 can be expanded in a gas expander 152, such as a power-producing nitrogen expander, fluidly coupled to the CO_2 separator 148. As depicted in FIGS. 1-3, the gas expander 152 can be optionally coupled to the inlet compressor 118 through a common shaft 154 or other mechanical, electrical, or other power coupling, thereby allowing a portion of the power generated by the gas expander 152 to drive the inlet compressor 118. After expansion in the gas expander 152, an exhaust gas 156, consisting primarily of nitrogen, can be vented to the atmosphere or implemented into other downstream applications known in the art. For example, the expanded nitrogen stream can be used in an evaporative cooling process configured to further reduce the temperature of the exhaust gas as generally described in the concurrently filed U.S. Patent Application entitled "Stoichiometric Combustion with Exhaust Gas Recirculation and Direct Contact Cooler," the contents of which are hereby incorporated by reference to the extent not inconsistent with the present disclosure. In at least one embodiment, the combination of the gas expander 152, inlet compressor 118, and CO_2 separator can be characterized as an open Brayton cycle, or the third power producing component of the system 100.

While the combination or coupling of the gas expander 152 and the inlet compressor 118 may resemble an open Brayton cycle, the gas expander 152, whether coupled or uncoupled from the inlet compressor 118, provides a third power producing component of the system 100. For example, the gas expander 152 can be used to provide power to other applications, and not directly coupled to the stoichiometric compressor 118. For example, there may be a substantial mismatch between the power generated by the expander 152 and the requirements of the compressor 118. In such cases, the expander 152 could be adapted to drive a smaller compressor (not shown) that demands less power (or to drive the inlet compressor 118 and one or more additional facilities).

In yet other embodiments, as will be discussed below with reference to FIG. 8, the gas expander 152 can be replaced with a downstream compressor 188 configured to compress the residual stream 151 and generate a compressed exhaust gas 190 suitable for injection into a reservoir for pressure maintenance or EOR applications.

The EGR system 124 as described herein can be implemented to achieve a higher concentration of CO_2 in the working fluid of the power generation system 100, thereby allowing for more effective CO_2 separation for subsequent sequestration, pressure maintenance, or EOR applications. For instance, embodiments disclosed herein can effectively increase the concentration of CO_2 in the flue gas exhaust stream to about 10 vol % or higher. To accomplish this, the combustion chamber 110 can be adapted to stoichiometrically combust the incoming mixture of fuel 112 and compressed oxidant 114. In order to moderate the temperature of the stoichiometric combustion to meet expander 106 inlet temperature and component cooling requirements, a portion of the exhaust gas derived from the compressed recycle stream 144 can be injected into the combustion chamber 110 as a diluent. Thus, embodiments of the disclosure can essentially eliminate any excess oxygen from the working fluid while simultaneously increasing its CO_2 composition. As such, the gaseous exhaust stream 122 can have less than about 3.0 vol % oxygen, or less than about 1.0 vol % oxygen, or less than about 0.1 vol % oxygen, or even less than about 0.001 vol % oxygen. In some implementations, the combustion chamber 110, or more particularly, the inlet streams to the combustion chamber may be controlled with a preference to substoichiometric combustion to further reduce the oxygen content of the gaseous exhaust stream 122.

The specifics of exemplary operation of the system 100 will now be discussed. As can be appreciated, specific temperatures and pressures achieved or experienced in the various components of any of the embodiments disclosed herein can change depending on, among other factors, the purity of the oxidant used and the specific makes and/or models of expanders, compressors, coolers, etc. Accordingly, it will be appreciated that the particular data described herein is for illustrative purposes only and should not be construed as the only interpretation thereof. For example, in one embodiment described herein, the inlet compressor 118 can be configured as a stoichiometric compressor that provides compressed oxidant 114 at pressures ranging between about 280 psia and about 300 psia. Also contemplated herein, however, is aeroderivative gas turbine technology, which can produce and consume pressures of up to about 750 psia and more.

The main compressor 104 can be configured to recycle and compress recycled exhaust gas into the compressed recycle stream 144 at a pressure nominally above or at the combustion chamber 110 pressure, and use a portion of that recycled exhaust gas as a diluent in the combustion chamber 110. Because amounts of diluent needed in the combustion chamber 110 can depend on the purity of the oxidant used for stoichiometric combustion or the model of expander 106, a ring of thermocouples and/or oxygen sensors (not shown) can be associated with the combustion chamber and/or the expander. For example, thermocouples and/or oxygen sensors may be disposed on the outlet of the combustion chamber 110, on the inlet to the expander 106, and/or on the outlet of the expander 106. In operation, the thermocouples and sensors can be adapted to determine the compositions and/or temperatures of one or more streams for use in determining the volume of exhaust gas required as diluent to cool the products of combustion to the required expander inlet temperature. Additionally or alternatively, the thermocouples and sensors may be adapted to determine the amount of oxidant to be injected into the combustion chamber 110. Thus, in response to the heat requirements detected by the thermocouples and the oxygen levels detected by the oxygen sensors, the volumetric mass flow of compressed recycle stream 144 and/or compressed oxidant 114 can be manipulated or controlled to match the demand. The volumetric mass flow rates may be controlled through any suitable flow control systems.

In at least one embodiment, a pressure drop of about 12-13 psia can be experienced across the combustion chamber **110** during stoichiometric combustion. Combustion of the fuel **112** and the compressed oxidant **114** can generate temperatures between about 2000° F. and about 3000° F. and pressures ranging from 250 psia to about 300 psia. Because of the increased mass flow and higher specific heat capacity of the CO_2-rich working fluid derived from the compressed recycle stream **144**, a higher pressure ratio can be achieved across the expander **106**, thereby allowing for higher inlet temperatures and increased expander **106** power.

The gaseous exhaust stream **122** exiting the expander **106** can have a pressure at or near ambient. In at least one embodiment, the gaseous exhaust stream **122** can have a pressure of about 15.2 psia. The temperature of the gaseous exhaust stream **122** can range from about 1180° F. to about 1250° F. before passing through the HRSG **126** to generate steam in line **130** and a cooled exhaust gas **132**. The cooled exhaust gas **132** can have a temperature ranging from about 190° F. to about 200° F. In one or more embodiments, the cooling unit **134** can reduce the temperature of the cooled exhaust gas **132** thereby generating the cooled recycle gas stream **140** having a temperature between about 32° F. and 120° F., depending primarily on wet bulb temperatures in specific locations and during specific seasons.

According to one or more embodiments, the boost compressor **142** can be configured to elevate the pressure of the cooled recycle gas stream **140** to a pressure ranging from about 17.1 psia to about 21 psia. As a result, the main compressor **104** receives and compresses a recycled flue gas working fluid with a higher density and increased mass flow, thereby allowing for a substantially higher discharge pressure while maintaining the same or similar pressure ratio. In at least one embodiment, the temperature of the compressed recycle stream **144** discharged from the main compressor **104** can be about 800° F., with a pressure of around 280 psia.

The following table provides testing results and performance estimations based on combined-cycle gas turbines, with and without the added benefit of a boost compressor **142**, as described herein.

TABLE 1

Triple-Cycle Performance Comparison

	Recirc. Cycle w/o Boost Compressor	Recirc. Cycle w/ Boost Compressor
Power (MW)		
Gas Turbine Expander Power	1055	1150
Main Compressor	538	542
Fan or Boost Compressor	13	27
Inlet Compressor	283	315
Total Compression Power	835	883
Net Gas Turbine Power	216	261
Steam Turbine Net Power	395	407
Standard Machinery Net Power	611	668
Aux. Losses	13	15
Nitrogen Expander Power	156	181
Combined Cycle Power	598	653
Efficiency		
Fuel Rate (mBTU/hr)	5947	6322
Heat Rate (BTU/kWh)	9949	9680
Combined Cycle Eff. (% lhv)	34.3	35.2
CO_2 Purge Pressure (psia)	280	308

As should be apparent from Table 1, embodiments including a boost compressor **142** can result in an increase in expander **106** power (i.e., "Gas Turbine Expander Power") due to the increase in pressure ratios. Although the power demand for the main compressor **104** can increase, its increase is more than offset by the increase in power output of the expander **106**, thereby resulting in an overall thermodynamic performance efficiency improvement of around 1% lhv (lower heated value).

Moreover, the addition of the boost compressor **142** can also increase the power output of the nitrogen expander **152** and the CO_2 purge pressure in the purge stream **146** line. While the boost compressor **142** can increase the power output of the nitrogen expander **152**, it can be seen in Table 1 that the nitrogen expander **152** is a significant contributor to the efficiency of the overall system **100** with or without the boost compressor.

An increase in purge pressure of the purge stream **146** can lead to improved solvent treating performance in the CO_2 separator **148** due to the higher CO_2 partial pressure. Such improvements can include, but are not limited to, a reduction in overall capital expenditures in the form of reduced equipment size for the solvent extraction process.

Referring now to FIG. **2**, depicted is an alternative embodiment of the power generation system **100** of FIG. **1**, embodied and described as system **200**. As such, FIG. **2** may be best understood with reference to FIG. **1**. Similar to the system **100** of FIG. **1**, the system **200** of FIG. **2** includes a gas turbine system **102** coupled to or otherwise supported by an exhaust gas recirculation (EGR) system **124**. The EGR system **124** in FIG. **2**, however, can include an embodiment where the boost compressor **142** follows or may otherwise be fluidly coupled to the HRSG **126**. As such, the cooled exhaust gas **132** can be compressed in the boost compressor **142** before being reduced in temperature in the cooling unit **134**. Thus, the cooling unit **134** can serve as an aftercooler adapted to remove the heat of compression generated by the boost compressor **142**. As with previously disclosed embodiments, the water dropout stream **138** may or may not be routed to the HRSG **126** to generate additional steam **130**.

The cooled recycle gas stream **140** can then be directed to the main compressor **104** where it is further compressed, as discussed above, thereby generating the compressed recycle stream **144**. As can be appreciated, cooling the cooled exhaust gas **132** in the cooling unit **134** after compression in the boost compressor **142** can reduce the amount of power required to compress the cooled recycle gas stream **140** to a predetermined pressure in the succeeding main compressor **104**.

FIG. **3** depicts another embodiment of the low emission power generation system **100** of FIG. **1**, embodied as system **300**. As such, FIG. **3** may be best understood with reference to FIGS. **1** and **2**. Similar to the systems **100**, **200** described in FIGS. **1** and **2**, respectively, the system **300** includes a gas turbine system **102** supported by or otherwise coupled to an EGR system **124**. The EGR system **124** in FIG. **3**, however, can include a first cooling unit **134** and a second cooling unit **136**, having the boost compressor **142** fluidly coupled therebetween. As with previous embodiments, each cooling unit **134**, **136** can be a direct contact cooler, trim cooler, or the like, as known in the art.

In one or more embodiments, the cooled exhaust gas **132** discharged from the HRSG **126** can be sent to the first cooling unit **134** to produce a condensed water dropout stream **138** and a cooled recycle gas stream **140**. The cooled recycle gas stream **140** can be directed to the boost compressor **142** in order to boost the pressure of the cooled recycle gas stream **140**, and then direct it to the second cooling unit **136**. The second cooling unit **136** can serve as an aftercooler adapted to remove the heat of compression generated by the boost compressor **142**, and also remove additional condensed water via a water dropout stream **143**. In one or more embodiments, each water dropout stream **138**, **143** may or may not be routed to the HRSG **126** to generate additional steam **130**.

The cooled recycle gas stream **140** can then be introduced into the main compressor **104** to generate the compressed recycle stream **144** nominally above or at the combustion chamber **110** pressure. As can be appreciated, cooling the cooled exhaust gas **132** in the first cooling unit **134** can reduce the amount of power required to compress the cooled recycle gas stream **140** in the boost compressor **142**. Moreover, further cooling exhaust in the second cooling unit **136** can reduce the amount of power required to compress the cooled recycle gas stream **140** to a predetermined pressure in the succeeding main compressor **104**.

Referring now to FIG. **4**, depicted is another embodiment of a low emission power generation system **400**, similar in some respects to the system **300** of FIG. **3**. As such, the system **400** of FIG. **4** may be best understood with reference to FIGS. **1** and **3**. It should be noted, however, that individual embodiments, or combinations thereof disclosed with reference to FIGS. **1-3** can be implemented and/or omitted in conjunction with the system **400** of FIG. **4** without departing from the scope of the disclosure. For example, the specific facilities and equipment incorporated into the EGR system **124** may vary as described elsewhere herein.

As described above, the temperature of the compressed recycle stream **144** discharged from the main compressor **104** can be about 800° F., and exhibit pressures of around 280 psia. Consequently, the purge stream **146** tapped from the compressed recycle stream **144** can exhibit similar temperatures and pressures. It should be noted once again that specific temperatures and pressures will inevitably change depending on the specific make and model of expanders, compressors, coolers, etc. Since the pressure is much higher than those found in conventional natural gas combined-cycle (NGCC) systems with post-combustion CO_2 recovery, it facilitates the use of a less energy-intensive gas treating process in the CO_2 separator **148**. For example, such elevated temperatures and pressures, in combination with a substantial lack of oxygen resulting from the stoichiometric combustion undertaken in the combustion chamber **110**, can allow for the use of a hot potassium carbonate solvent to extract CO_2 from the purge stream **146**. In other embodiments, CO_2 selective adsorbents can include, but are not limited to, monoethanolamine ("MEA"), diethanolamine ("DEA"), triethanolamie ("TEA"), potassium carbonate, methyldiethanolamine ("MDEA"), activated methyldiethanolamine ("aMDEA"), diglycolamine ("DGA"), diisopropanolamine ("DIPA"), piperazine ("PZ"), derivatives thereof, mixtures thereof, or any combination thereof. Other suitable adsorbents and techniques can include, but are not limited to, propylene carbonate physical adsorbent solvent as well as other alkyl carbonates, dimethyl ethers of polyethylene glycol of two to twelve glycol units (Selexol™ process), n-methyl-pyrrolidone, sulfolane, and use of the Sulfinol® Gas Treatment Process.

In one embodiment, the gas treating processes in the CO_2 separator **148** can require the temperature of the purge stream **146** to be cooled to about 250° F.-300° F. To achieve this, the purge stream **146** can be channeled through a heat exchanger **158**, such as a cross-exchange heat exchanger fluidly coupled to the residual stream **151**. In some embodiments, the heat exchanger **158** may be a shell-and-tube heat exchanger, a plate heat exchanger, a plate-and-frame heat exchanger, or any other heat exchanger known in the art and suitable to cool the purge stream **146** by facilitating the transfer of heat from the purge stream **146** to the residual stream **151** by indirect contact through another material (e.g, through metal tube walls in shell-and-tube heat exchanger or through metal plates in a plate or plate-and-frame heat exchanger). In at least one embodiment, extracting CO_2 from the purge stream **146** in the CO_2 separator **148** can leave a nitrogen-rich residual stream **151** at or near the elevated pressure of the purge stream **146** and at a temperature of about 150° F. In one embodiment, the heat energy associated with cooling the purge stream **146** can be extracted via the heat exchanger **158** and used to re-heat the residual stream **151**, thereby generating a heated nitrogen vapor **160** having a temperature of about 750° F. and a pressure of around 270-280 psia. While heat exchange with the purge stream **146** is one manner of heating the residual stream **151**, other methods are within the scope of the present disclosure. For example, in one or more embodiments supplemental heating of residual stream **151** may be done by using the HRSG **126** to supply heat as well as well as to generate steam **130**. Other exemplary methods are described herein and should not be considered an exhaustive listing of available methods to heat the residual stream **151**.

In one or more embodiments, the heated nitrogen vapor **160** can then be expanded through the gas expander **152**. Accordingly, cross-exchanging the heat in the heat exchanger **158** can be configured to capture a substantial amount of compression energy derived from the main compressor **104** and use it to maximize the power extracted from the gas expander **152**, and optionally power the stoichiometric inlet compressor **118**. In at least one embodiment, the exhaust gas **156**, consisting primarily of nitrogen at atmospheric pressure, can be harmlessly vented to the atmosphere or implemented into other downstream applications known in the art. Exemplary downstream applications, such as evaporative cooling processes, are described in the concurrently filed U.S. Patent Application entitled "Stoichiometric Combustion with Exhaust Gas-Recirculation and Direct Contact Cooler," as stated above.

During start-up of the system **400** and during normal operation when the gas expander **152** may be unable to supply all the required power to operate the inlet compressor **118**, at least one motor **162**, such as an electric motor, can be used synergistically with the gas expander **152**. For instance, the motor(s) **162** can be sensibly sized such that during normal operation of the system **400**, the motor(s) **162** can be configured to supply the power short-fall from the gas expander **152**. Additionally or alternatively, there may be times during operation when the gas expander **152** produces more energy than required by the inlet compressor **118**. In some implementations, the at least one motor **162** may be a motor/generator system that may be selectively configured to provide power, such as from the electric grid, to the compressor or to generate electricity from the power generated by the turbine **152**.

Referring now to FIG. **5**, depicted is another embodiment of a low emission power generation system **500**, similar in some respects to the system **400** of FIG. **4**. As such, the entire system **500** of FIG. **5** will not be described in detail but may be best understood with reference to FIGS. **1**, **3**, and **4**. It should be noted that any embodiment disclosed with reference to FIGS. **1-4** can be implemented individually or in combination into the system **500**, without departing from the scope of the disclosure.

In an embodiment, once the purge stream **146** is tapped from the compressed recycle stream **144**, its temperature can be increased by a catalytic process undertaken in a catalysis apparatus **164**. In operation, the catalysis apparatus **164** can be configured to reduce the oxygen and/or carbon monoxide content in the purge stream, and convert it into residual CO_2 and heat. The catalysis apparatus **164** can be a single device or a plurality of devices in parallel, series, or a combination of parallel and series. In one embodiment, the catalysis apparatus **164** can be a small device requiring only a small amount of power to operate. One exemplary catalysis apparatus **164** can include an oxygen reduction catalyst that is normally used in a HRSG to meet emissions requirements. Such a system generally is not designed to remove large amounts of oxygen, but if significant amounts of oxygen remain in compressed recycle stream **144**, the purge stream **146** can be recycled through the catalysis apparatus **164** more than once before further processing or use, e.g., compression and injection for enhanced oil recovery (EOR), CO_2 separation, etc.

Moreover, any residual hydrocarbons in the purge stream **146** can also be combusted in the catalysis apparatus **164**. In at least one embodiment, the temperature of the purge stream **146** can be increased from about 785° F. to about 825° F. by the complete catalytic conversion of about 1200 ppm oxygen present in the purge stream **146**. Illustrative catalysts that can be used in the catalysis apparatus **164** can include, but are not limited to, Nickel, Platinum, Rhodium, Ruthenium, Palladium, or derivatives thereof, mixtures thereof, any combination thereof. This increase in heat content can be introduced into the heat exchanger **158** and cross-exchanged with the nitrogen-rich residual stream **151**, thereby resulting in a higher temperature of heated nitrogen vapor **160** and facilitating a more effective and powerful expansion process in the gas expander **152**.

As still further enhancements to the triple-cycle system including the gas expander **152**, in one or more embodiments, water can be injected via line **166** into the heated nitrogen vapor **160** to increase the mass throughput of the gas expander **152** and consequently increase the power generated. The water can be treated atomized water or steam. In at least one embodiment, the supplementary power provided by the injection of atomized water or steam can increase the power output from about 169 MW to about 181 MW. As can be appreciated, the power output will generally be dependent on the make and model of the gas expander. It should be noted that injecting atomized water or steam via line **166** into the heated nitrogen vapor **160** in order to increase the mass flow through the gas expander **152** can be implemented into any of the embodiments disclosed herein, without departing from the scope of the disclosure.

Referring to FIG. **6**, depicted is another embodiment of a low emission power generation system **600**, similar to the system **500** of FIG. **5**. As such, the entire system **600** will not be described in detail but may be best understood with reference to FIG. **5**. In one embodiment, the system **600** can include an additional stoichiometric combustion chamber **168** disposed prior to the gas expander **152**. The combustion chamber **168** can be configured to stoichiometrically combust a combination of fuel **170** and compressed oxidant **172**, much like the combustion chamber **110** described above, in order to generate a discharge stream **174** at an elevated temperature and pressure. In one embodiment, the fuel **170** and the compressed oxidant **172** can be derived from the same source as the fuel **112** and the compressed oxidant **114**, respectively, that are fed into the first combustion chamber **110**. In implementations incorporating the additional combustion chamber **168**, the heat exchanger **158** may cool the purge stream through other means, such as by heating one or more other streams in the system **600** or elsewhere. For example, the heat exchanger on the purge stream may provide additional heat to the HRSG or to a reforming process.

In other embodiments, especially embodiments where zero CO_2 emissions is desired or required, the fuel **170** can consist primarily of hydrogen. In at least one embodiment, the hydrogen fuel can be produced by reforming methane in the HRSG **126**, or a separate HRSG (not shown). After the reformation of the methane and a water gas shift, the CO_2 in the hydrogen product stream can be removed in an absorption tower (not shown), for example, in the CO_2 separator **148**. The hydrogen could then be blended with some of the nitrogen in the heated nitrogen vapor **160** stream within the combustion chamber **168** to make an acceptable gas turbine fuel.

The heated nitrogen vapor **160** discharged from the heat exchanger **158**, or discharged from the CO_2 separator **148**, can serve as a diluent configured to moderate the temperature of combustion and the discharge stream **174**. In at least one embodiment, the discharge stream **174** exiting the combustion chamber **168** can have a temperature of about 2500° F. before being expanded in the gas expander to create mechanical power. As will be appreciated, the combination of the gas expander **152**, combustion chamber **168**, and inlet compressor **118** can be characterized as a separate standard gas turbine system, where the inlet compressor **118** becomes the compressor end and the gas expander **152** becomes the expander end of the gas turbine.

In one or more embodiments, the exhaust gas **156** can have a temperature of about 1100° F. In at least one embodiment, the exhaust gas **156** can be directed to the HRSG **126** to recover the heat as power in the steam gas turbine **128**. In other embodiments, the exhaust gas **156** can be directed to an external HRSG and steam gas turbine (not shown) to generate power for other applications. In any event, the nitrogen-rich residual stream **151** may be disposed of in any of the manners discussed herein, such as via nitrogen vent, via sequestration, EOR, or pressure maintenance operations, etc., after passing through the expander **152**.

Referring now to FIG. **7**, depicted is another embodiment of a low emission power generation system **700**, similar to the system **600** of FIG. **6**. As such, the entire system **700** of FIG. **7** will not be described in detail but may be best understood with reference to FIG. **6** and its accompanying description. Instead of utilizing a separate inlet compressor **118** and nitrogen expander **152** (see FIGS. **1-6**), the system **700** as depicted in FIG. **7** can include a second gas turbine system **702**, having a second compressor **176** and second expander **178**. In one or more embodiments, the second compressor **176** can receive and compress a second feed oxidant **180**. Similar to the feed oxidant **120** shown and described above in FIGS. **1-6**, the second feed oxidant **180** can include any suitable gas containing oxygen, such as air, oxygen-rich air, or combinations thereof. The second compressor **176** can be configured to compress the second feed oxidant **180** and generate a second compressed oxidant **182**. As depicted, the compressed oxidant **114** required for the combustion chamber **110** can be supplied or extracted from the second compressed oxidant **182** stream and serve the same function as generally described above.

In operation, the combustion chamber **168** can be configured to stoichiometrically combust a combination of the fuel **170** and the second compressed oxidant **182** in order to generate a discharge stream **174** at an elevated temperature and pressure. In one or more embodiments, the nitrogen vapor **160** from the heat exchanger **158** or the residual stream from the CO_2 separator **148** can be utilized as a diluent configured to moderate the temperature of combustion in the second combustion chamber **168**. In one embodiment, the fuel **170** can be derived from the same source as the fuel **112** fed into the first combustion chamber **110**, such as a hydrocarbon fuel. In other embodiments where zero CO_2 emissions is desired or required, the fuel **170** can consist primarily of hydrogen, as generally described above with reference to FIG. **6**.

If a hydrocarbon fuel is used, then CO_2 emissions will naturally result. However, because of the use of a largely-pure nitrogen stream as a diluent, the resulting CO_2 emissions will be significantly less than when compared with a conventional NGCC power plant. For example, in one embodiment, the CO_2 emissions resulting from the system **700** will only be about 80 lbs/MWhr as compared with about 400 lbs/MWhr for a conventional NGCC power plant. In one or more embodiments, the exhaust gas **156** from the second expander **178** can have a temperature of about 1100° F. In at least one embodiment, the exhaust gas **156** can be directed to a second HRSG **184** to recover the heat as power in a separate steam gas turbine **186**. In alternative embodiments, however, the exhaust gas **156** can be directed to the first HRSG **126** to recover the heat as power in the steam gas turbine **128**. Here again, it can be understood that exhaust gas **156** may be vented or otherwise used in hydrocarbon recovery operations (not shown) as described above after passing through the second HRSG **184**.

As can be appreciated, the system **700** of FIG. **7** can allow a commercially-available gas turbine to be utilized instead of undergoing costly upgrades to obtain a custom-built air compressor and a custom-built expander. The system **700** can also produce more net power at a higher efficiency because the inlet temperature of the second expander **178** can reach temperatures around 2500° F.

Referring now to FIG. **8**, depicted is another embodiment of a low emission power generation system **800**, similar to the system **300** of FIG. **3**. As such, the entire system **800** of FIG. **8** will not be described in detail but may be best understood with reference to FIGS. **1** and **3**. It should be noted, however, that embodiments disclosed with reference to FIGS. **1**-**6** can be implemented individually or in combination with the system **800** of FIG. **8** without departing from the scope of the disclosure. In an exemplary embodiment, the residual stream **151**, consisting primarily of nitrogen derived from the CO_2 separator **148**, can be channeled to a downstream compressor **188**. The downstream compressor **188** can be configured to compress the residual stream **151** and generate a compressed exhaust gas **190** having a pressure of, for example, about 3400 psi or pressures otherwise suitable for injection into a reservoir for pressure maintenance applications.

Compressing the residual stream **151** with the downstream compressor **188** may prove advantageous in applications where methane gas is typically reinjected into hydrocarbon wells to maintain well pressures. According to embodiments disclosed herein, nitrogen can instead be injected into hydrocarbon wells and the residual methane gas can either be sold or otherwise used as a fuel in related applications, such as providing fuel for the fuel streams **112**, **170** (see FIGS. **6** and **7**).

With continuing reference to FIGS. **5**-**7**, the following table provides testing results and performance estimations based on systems without an expansion cycle (e.g., system **800** of FIG. **8**), systems without additional firing in the combustion chamber **168** (e.g., system **500** of FIG. **5**), and systems with additional firing in the combustion chamber **168** (e.g., systems **600**, **700** of FIGS. **6** and **7**, respectively). The data reflects a methane fuel **170** being fired for combustion.

TABLE 2

Triple-Cycle Performance Comparison

	Cycle - No Expansion	Cycle w/o Firing	Cycle w/ Firing
Power (MW)			
Gas Turbine Expander Power	1150	1150	1150
Main Compressor	542	542	542
Fan or Boost Compressor	27	27	27
Inlet Compressor	315	251	601
Total Compression Power	883	883	1170
Net Gas Turbine Power	258	258	−32
Steam Turbine Net Power	407	339	339
Standard Machinery Net Power	665	597	307
Aux. Losses	15	13	7
Nitrogen Expander power	0	203	1067
Supp. Steam Turbine Power	0	0	303
Combined Cycle Power Efficiency	650	787	1670
Fuel Rate (Mbtu/hr)	6322	6322	11973
Heat Rate (BTU/kWh)	9727	8037	7167
Combined Cycle Eff. (% lhv)	35.1	42.5	47.6
CO_2 Purge Pressure (psia)	308	308	308

As should be apparent from Table 2, embodiments with firing in the combustion chamber **168** can result in a significantly higher combined-cycle power output; almost double the power output when compared with embodiments not implementing firing in the combustion chamber **168**. Moreover, the overall thermodynamic performance efficiency exhibits a substantial uplift or improvement of around 3.3% lhv (lower heated value) for systems incorporating firing as disclosed herein, as opposed to embodiments not implementing such firing techniques.

While the present disclosure may be susceptible to various modifications and alternative forms, the exemplary embodiments discussed above have been shown only by way of example. However, it should again be understood that the disclosure is not intended to be limited to the particular embodiments disclosed herein. Indeed, the present disclosure includes all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

What is claimed is:

1. An integrated system, comprising:

a gas turbine system having a first combustion chamber configured to substantially stoichiometrically combust a first compressed oxidant and a first fuel in the presence of a compressed recycle stream such that there is a ratio of oxygen supplied to oxygen required for stoichiometric combustion from 0.9:1 to 1.1:1, wherein the first combustion chamber directs a first discharge stream to an expander to generate a gaseous exhaust stream and at least partially drive a main compressor;

an exhaust gas recirculation system comprising at least one boost compressor configured to receive and boost the pressure of the gaseous exhaust stream before directing the gaseous exhaust stream into the main compressor, wherein the main compressor compresses the gaseous exhaust stream and thereby generates the compressed recycle stream, the compressed recycle stream acting as a first diluent to moderate the temperature of the first discharge stream;

a CO_2 separator fluidly coupled to the compressed recycle stream via a purge stream;

a second combustion chamber fluidly coupled to the CO_2 separator via a residual stream consisting primarily of nitrogen derived from the CO_2 separator, wherein the second combustion chamber is configured to substantially stoichiometrically combust a second fuel and a second compressed oxidant in the presence of the residual stream, the residual stream acting as a second diluent to moderate a temperature of combustion in the second combustion chamber, and wherein the first and second compressed oxidants and the first and second fuels are derived from same sources, respectively;

a heat exchanger fluidly coupled to both the purge stream and the residual stream and adapted to transfer heat from the purge stream to the residual stream prior to injection of the residual stream into the second combustion chamber; and

a gas expander fluidly coupled to the second combustion chamber via a second discharge stream.

2. The system of claim **1**, further comprising first and second cooling units fluidly coupled to the at least one boost compressor, the first cooling unit being configured to receive and cool the gaseous exhaust stream before introduction to the at least one boost compressor, and the second cooling unit being configured to receive the gaseous exhaust stream from the at least one boost compressor and further cool the gaseous exhaust stream to generate a cooled recycle gas.

3. The system of claim **1**, wherein the heat exchanger is configured to transfer heat from the purge stream to the residual stream through an intermediate material to reduce a temperature of the purge stream and simultaneously increase the temperature of the residual stream.

4. The system of claim **1**, further comprising a catalysis apparatus disposed in association with the purge stream, the catalysis apparatus being configured to increase a temperature of the purge stream prior to entering the heat exchanger.

5. The system of claim **1**, wherein the gas expander is configured to expand the second discharge stream and thereby generate mechanical power and an exhaust gas.

6. The system of claim **5**, further comprising an inlet compressor driven by the mechanical power generated by the gas expander, wherein the inlet compressor is configured to provide the first and second compressed oxidants.

7. A method of generating power, comprising:

stoichiometrically combusting a first compressed oxidant and a first fuel in a first combustion chamber and in the presence of a compressed recycle stream such that there is a ratio of oxygen supplied to oxygen required for stoichiometric combustion from 0.9:1 to 1.1:1, thereby generating a first discharge stream, wherein the compressed recycle stream acts as a first diluent to moderate a temperature of the first discharge stream;

expanding the first discharge stream in an expander to at least partially drive a first compressor and generate a gaseous exhaust stream;

directing the gaseous exhaust stream into the first compressor, wherein the first compressor compresses the gaseous exhaust stream and thereby generates the compressed recycle stream;

extracting a portion of the compressed recycle stream to a CO_2 separator via a purge stream, the CO_2 separator being fluidly coupled to a second combustion chamber via a residual stream derived from the CO_2 separator and consisting primarily of nitrogen;

using a heat exchanger fluidly coupled to both the purge stream and the residual stream to transfer heat from the purge stream to the residual stream to increase the temperature of the residual stream prior to injection of the residual stream into the second combustion chamber;

substantially stoichiometrically combusting a second compressed oxidant and a second fuel in the second combustion chamber in the presence of the residual stream to generate a second discharge stream, wherein the first and second compressed oxidants and the first and second fuels are derived from same sources, respectively;

moderating a temperature of combustion in the second combustion chamber with the residual stream discharged from the CO_2 separator acting as a second diluent;

expanding the second discharge stream in a gas expander; and

using at least one of a boost compressor and a first cooling unit adapted to increase the mass flow rate of the gaseous exhaust stream to generate recycle gas.

8. The method of claim **7**, comprising cooling the gaseous exhaust stream with the first cooling unit fluidly coupled to the at least one boost compressor, the first cooling unit being configured to receive and cool the gaseous exhaust stream before introduction to the at least one boost compressor.

9. The method of claim **8**, further comprising cooling the gaseous exhaust stream from the at least one boost compressor with a second cooling unit fluidly coupled to the at least one boost compressor to generate the recycle gas.

10. The method of claim **7**, further comprising driving an inlet compressor with the mechanical power generated by the gas expander, the inlet compressor being configured to generate the first and second compressed oxidants.

11. The method of claim **7**, wherein the heat exchanger is configured to transfer heat from the purge stream to the residual stream through an intermediate material to reduce a temperature of the purge stream and simultaneously increase the temperature of the residual stream.

12. The method of claim **11**, further comprising increasing the temperature of the purge stream by combusting oxygen and remaining fuel in a catalysis apparatus disposed within the purge stream prior to the heat exchanger.

13. An integrated system, comprising:

a first gas turbine system, comprising:

a first compressor configured to receive and compress a recycled exhaust gas and provide a first compressed recycle stream;

a first combustion chamber configured to receive the first compressed recycle stream, a first compressed oxidant, and a first fuel stream, the first combustion chamber being adapted to substantially stoichiometrically combust the first fuel stream and first compressed oxidant such that there is a ratio of oxygen supplied to oxygen required for stoichiometric combustion from 0.9:1 to 1.1:1, wherein the first compressed recycle stream serves as a first diluent to moderate combustion temperatures in the first combustion chamber;

a first expander coupled to the first compressor and configured to receive a first discharge from the first combustion chamber and generate the recycled exhaust gas and at least partially drive the first compressor; and a boost compressor configured to increase the pressure of the recycled exhaust gas before injection into the first compressor to provide the first compressed recycle stream;

a purge stream taken from the first compressed recycle stream and treated in a CO_2 separator to provide a CO_2 stream and a residual stream, the residual stream primarily comprising nitrogen; and

a second gas turbine system fluidly coupled to the first gas turbine system via the purge stream, the second gas turbine system comprising:

a second compressor configured to receive and compress a feed oxidant and generate a second compressed oxidant, the first compressed oxidant being derived at least partially from the second compressed oxidant;

a second combustion chamber configured to receive the second compressed oxidant, the residual stream, and a second fuel stream, the second combustion chamber being adapted to substantially stoichiometrically combust the second fuel stream and second compressed oxidant in the presence of the residual stream, wherein the residual stream serves as a second diluent to moderate combustion temperatures in the second combustion chamber and the first and second fuels are derived from a same source;

a heat exchanger fluidly coupled to both the purge stream and the residual stream and adapted to transfer heat from the purge stream to the residual stream prior to injection of the residual stream into the second combustion chamber; and

a second expander coupled to the second compressor and configured to receive a second discharge from the second combustion chamber and generate an exhaust and at least partially drive the second compressor.

14. The system of claim **13**, wherein the second gas turbine system further comprises a heat recovery steam generator configured to receive the exhaust from the second expander and provide steam for a steam gas turbine.

15. The system of claim **13**, wherein the heat exchanger is configured to transfer heat from the purge stream to the residual stream through an intermediate material to reduce a temperature of the purge stream and simultaneously increase the temperature of the residual stream.

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